Geologic Storage of Carbon Dioxide and Enhanced Oil Recovery II: Cooptimization of Storage and Recovery

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Abstract

Geologic sequestration of carbon dioxide (CO_2) in oil and gas reservoirs is one possibility to reduce the amount of CO_2 released to the atmosphere. Carbon dioxide injection has been used in enhanced oil recovery (EOR) processes since the 1970s; the traditional approach is to reduce the amount of CO_2 injected per barrel of oil produced. For a sequestration process, however, the aim is to maximize both the amount of oil produced and the amount of CO_2 stored. It is not readily apparent how this aim is achieved in practice. In this study, several strategies are tested via compositional reservoir simulation to find injection and production procedures that "cooptimize" oil recovery and CO_2 storage. Flow simulations are conducted on a synthetic, three dimensional, heterogeneous reservoir model. The reservoir description is stochastic in that multiple realizations of the reservoir are available. The reservoir fluid description is compositional and incorporates 14 distinct components. The results show that traditional reservoir engineering techniques such as injecting CO_2 and water in sequential fashion, a so-called water-alternating-gas process, are not conducive to maximizing CO_2 stored within the reservoir. A well control process that shuts in (i.e., closes) wells producing large volumes of gas and allows shut-in wells to open as reservoir pressure increases is the most successful strategy for cooptimization. This result holds for immiscible and miscible gas injection. The strategy appears to be robust in that full physics simulations employing multiple realizations of the reservoir model all confirmed that the well-control technique produced the maximum amount of oil and simultaneously stored the most CO_2 .

Key words: CO_2 sequestration, mobility control, reservoir simulation

1 Introduction

Measured atmospheric CO_2 concentrations for the last two hundred and fifty years show that the concentration of CO_2 has increased from 270 to 370 parts per million (ppm). It is estimated that half of this amount has occurred in the last 50 years. The increase is mainly attributed to the combustion of fossil fuels for energy production [1]. One possible solution to reduce atmospheric CO_2 emissions is geologic sequestration of CO_2. This is summarized as the storage of CO_2 deep within the earth instead of releasing it to the atmosphere. Carbon dioxide is already injected into oil reservoirs to increase oil recovery. Anthropogenic CO_2 could substitute for the naturally occurring CO_2 currently injected. Additional geologic options include unmineable coal beds, deep saline aquifers, and mined salt domes.

Oil reservoirs are good candidates for sequestration because physical and legal

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infrastructure already exists for CO_2 injection. The main factor setting the efficiency of EOR with CO_2 injection is the miscibility of CO_2 in the oil phase [2–4]. At pressures greater than minimum miscibility pressure (MMP), oil and CO_2 are mutually soluble. The dissolved CO_2 reduces the viscosity of the oil and also causes swelling of the oil phase. Thus, CO_2 injection projects are preferred for oil with densities ranging from 29 to 48 $^\circ$ API (882 to 788 kg/m^3) and reservoir depths from 760 to 3700 m below ground surface [5]. If the only considerations are depth and gravity, 80 % of the worlds reservoirs qualify for EOR with CO_2 [6]. To date, injection processes have been designed to minimize the amount of CO_2 injected per barrel of oil produced thereby minimizing the purchase cost of CO_2. However, when the aim is to store carbon dioxide, the design question changes significantly [7]. Oil recovery processes need to be modified to leave the maximum amount of CO_2 in the reservoir at the completion of operations as well as maximizing the oil recovery.

This paper is the second in a two-part series examining cooptimization of oil recovery and geologic storage of CO_2. The previous paper [10] presented a workflow for cooptimization and developed a technique for assessing uncertainty in flow predictions. In this study, our main goal is to find carbon dioxide injection strategies leading to cooptimization. The focus here is effective methods that co-optimize CO_2 storage and oil recovery for a given reservoir and fixed well placement. It is assumed that sequestration services provide significant revenue. The reservoir model and fluids are summarized next. Then, we focus on developing CO_2 injection scenarios. Results are obtained using a compositional, reservoir flow simulator. Next, we confirm that the production scenarios producing favorable results for one reservoir model also are favorable for other equiprobable models. Conclusions round out the paper.

2 Reservoir Description

The synthetic reservoir description known as PUNQS3 [8,9] is chosen. Our implementation of PUNQS3 is as described earlier [10]. The reservoir is roughly 28 m thick with a pore (i.e., void) volume of 30 x10^6 m^3. Initially, 60 % of the pore space is filled with oil. Reservoir shape is anticlinal (i.e., dome shaped) and it is bounded by faults and underlain by an aquifer, as shown in Figure 1. Darkly shaded portions of Fig. 1 locate the regions of the greatest absolute rock peremability (permeability is a quantitative measure of the conductivity of the rock to fluid). The average horizontal permeability is about 100 md (1 md = 1 x10^{-15} m^2) and the average porosity (void fraction) is 0.20. Fault location on Fig. 1 is called out by a thick dotted line. Arrows indicate the location of injection (down) and production (up) wells. For most simulations in this work, we employ the "truth" model as described in ref. [10] and illustrated in Fig. 1.

The reservoir fluid description is given in Table 1 [10]. The reservoir fluid is moderately dense (910 kg/m^3) and viscous. Pure CO_2 and the reservoir fluid are not mutually miscible at reservoir pressure. The minimum pressure for achieving misciblity (MMP) for pure CO_2 is in excess of 600 atm (60.8 MPa), whereas the initial reservoir pressure is 250 atm (25.3 MPa). Thus, the reservoir is not a prototypical candidate for CO_2-EOR. Because microscopic displacement efficiency approaches unity when the injection gas and oil are miscible, we also explore solvent injection as a means of oil recovery. Table 2 lists the compositions of the two injection gases. The solvent is designed to contain a large percentage of CO_2 with lesser amounts of ethane (C_2), propane (C_3), and butane (C_4) that allow miscibility to develop at pressures below 250 atm.

Flow within the reservoir is described by the multiphase extension of Darcy's law [11]. The effective permeability of the rock to each phase depends on S_i the fraction of the pore space filled by phase i. Note that the relative permeability, k_{ri}, is defined as the effective permeability upon the absolute rock permeability. As the saturation of a phase declines, relative permeability to that phase also declines. The specific relative permeability functions employed in this work are shown in Fig. 2. The subscripts o and w refer to the flow of oil and water, respectively, in a water-oil system, whereas the subsripts g and og refer to the flow of gas and oil, respectively, in an oil-gas system. The Stone II model is used to obtain three-phase relative permeability functions from two-phase data [12]

3 Injection Scenarios

Our main goal is to find injection scenarios leading to maximum oil recovery and maximum emplacement of CO_2 in the reservoir. To achieve this goal, we performed reservoir flow simulations with Eclipse300 [13], a fully-compositional, three-dimensional finite-difference based reservoir simulator. A variety of schemes were tested that are summarized as

- gas injection after waterflooding (GAW)
- water alternating gas drive (WAG)
- gas injection with active production and injection well constraints (well control or WC)
- switch from solvent gas injection to pure CO_2 injection

Pure CO_2 and the solvent gas are used in each of the scenarios. The first two schemes resemble conventional oil recovery methods. Gas injection after waterflooding represents a project where water is used to maintain pressure and drive oil from the reservoir. After some volume of water injection, the project is converted to gas injection as a means of sequestering CO_2. For simulation, production wells operate at a fixed pressure of 175 bars. This pressure is the bottomhole pressure (BHP) within the portion of the well just adjacent to the producing formation. Water is injected at a rate of 1000 m^3/day per well until injection is switched to CO_2 at 400,000 m^3/day (volumes at standard conditions). The size of the initial water injection was varied from 0.1 to 1.0 PV in steps of 0.1 PV. Here, PV (short for pore volume) is a dimensionless quantity referring to the volume of fluid injected (at reservoir conditions) divided by the pore (void) volume of the reservoir. Hence, 0.1 PV signifies injection of a fluid volume equal to 10 % of the reservoir volume.

The WAG scheme injects water and CO_2 in alternating slugs. The water helps to reduce the mobility of CO_2 within the reservoir making CO_2 a more effective displacement agent. In situations where gravity is significant, the more dense water sweeps the lower portions of the resevoir while the more buoyant gas sweeps upper portions. Again, production wells operate at a fixed pressure of 175 bars. The injection rate of water is 1000 m^3/day, whereas that of CO_2 or solvent is 400,000 m^3/day (at standard conditions). Equal volumes of water and gas (at reservoir conditions) are injected during each slug because the optimal WAG ratio (volume of water to that of gas in a slug) is approximately 1 for the combination of relative permeability curves and phase viscosities [14]. Slug sizes of 0.001, 0.01, 0.1, and 1 PV are employed.

The third scheme aims to maximize the mass of CO_2 injected while not reducing oil recovery. The well control parameters are the producing gas-oil ratio (GOR) and the injection pressure, where the producing GOR is the volumetric flow rate of gas produced upon the oil production rate. Table 3 summarizes the three well-control schemes that were tested. Producer GOR refers to the GOR threshold that causes a well to be shut in. The pressure columns are the injection or reservoir pressure where production wells are opened to avoid over-pressurizing and thereby damaging the reservoir. Every time a production well is opened, the threshold GOR for shutting in a well is increased by the increment indicated. Numerical experimentation showed that no or small increments in the threshold GOR caused wells to turn off rather frequently and this reduced oil production significantly. The various scenarios are simulated with both pure CO_2 injection and miscible solvent gas injection.

The final scheme employs initially a solvent gas that is rich in light hydrocarbon components. Miscibility of the injection gas with the oil leads to excellent recovery. Later during injection, the solvent gas is switched to pure CO_2. This helps to reduce the volume of relatively expensive solvent required, promotes recovery of the hydrocarbon gas components, as well as leads to maximum concentration of CO_2 in gas-filled pore space. Wells are operated as in the well control scenario. The time for the switching from solvent gas injection to pure CO_2 is the main parameter examined.

3.1 Evaluation of Scenarios

In a cooptimization scheme, it may be appropriate to allow some volume of gas to cycle through the reservoir as a means of obtaining maximum CO_2 storage. Any produced gas, however, must be recompressed to injection pressure before it can be recycled to the reservoir. That is, there is an energy penalty associated with gas cycling. To allow the possibility of gas cycling but to also account for the energy penalty, the net cumulative oil recovery, N_p^*, is defined as

$$N_p^* = N_p - E \tag{1}$$

where N_p is the cumulative oil recovery. The second term on the right is the energy needed, in oil equivalent units, to compress the produced injection gas to injection pressure. It is expressed as [15]

$$E = \frac{3.1815\text{x}^{-7}}{\gamma} P_{in} Q_{in} \left[\left(\frac{P_{out}}{P_{in}} \right)^{\gamma} - 1 \right] t \tag{2}$$

where γ is the compressibility factor (0.23 for CO_2), P is pressure (lb_f/ft^2), Q is flow rate (ft^3/min), and the subscripts in and out refer to the low and high pressure sides of the compressor. In Eq. 2, E has units of barrels of oil and t is in days. Thus, N_p^* is the net production of oil discounted by the amount of energy needed to cycle gas through the reservoir.

Traditional CO_2–EOR design seeks the maximum recovery while injecting the minimum amount of CO_2. In equation form the design, D_{trad}, reads:

$$D_{trad} = \max(N_p^*) \cup \min(V^i_{\text{CO}_2}) \tag{3}$$

where $V^i_{\text{CO}_2}$ is the volume of CO_2 injected to achieve the recovery N_p^*.

Clearly, traditional design is inadequate for CO_2 sequestration operations because the primary goal is to leave substantial CO_2 behind at the end of the recovery process while obtaining the same, or greater, recovery as a traditional process. Our approach to cooptimization design begins with an objective function combining dimensionless oil recovery and reservoir utilization:

$$f = w_1 \frac{N_p^*}{OIP} + w_2 \frac{V^R_{\mathrm{CO_2}}}{V^R} \tag{4}$$

where w_1 ($0 \le w_1 \le 1$) and w_2 ($= 1 - w_1$) are weights, OIP is the volume of oil in place at the start of cooptimization operations, $V^R_{\mathrm{CO_2}}$ is the volume of CO_2 stored in the reservoir, and V^R is the volume of the pore (void) space of the reservoir. The OIP is not necessarily equal to the original oil held in the reservoir, because recovery operations prior to CO_2 injection displace some oil. In short, f accounts for the oil displaced and recovered as well as the fraction of the reservoir volume filled with CO_2.

Reservoirs generally hold a fair fraction of water and gas, in addition to oil. Equation 4 makes explicit the notion that pore space emptied of oil, water, or natural gas should be filled, to the greatest extent, with CO_2. That is, sequestration in an oil reservoir is not simply a volumetric substitution of oil with CO_2 [7]. A scheme that injects, for instance, a large volume of water has a lesser f, for nonzero w_2, because the second term on the right of Eq 4 is not maximized. The design equation for cooptimization is thus stated as

$$D_{coop} = \max(f) \tag{5}$$

subject to a specified set of weights. Proper selection of weights is nontrivial and important for meeting process objectives. If the chief aim is to maximize oil recovery, w_1 is taken as 1, whereas if the goal is to increase CO_2 storage w_2 is taken as 1. The regulatory and tax structure for sequestration remains unclear and likely will vary from nation to nation. Here, we take equal weighting

($w_1 = w_2 = 0.5$) and place equal emphasis on oil recovery and CO_2 storage. Equal weighting implies equal value. In practice, weights will be chosen based on the revenue produced by oil recovery and CO_2 sequestered. In this work, the optimum is sought in a stochastic fashion by calculating the results of various scenarios. For generality, results are given as a function of time for all three weight combinations above. This allows identification of the effects of the injection process on oil recovery and CO_2 storage individually.

4 Results

Figure 3 summarizes the performance of the GAW, WAG, and WC schemes outlined above. For ease of interpretation, 8 cases are presented, however, 20 individual cases and numerous simulations were run to ensure generality. For consistency among the various injection–production scenarios, the recovery N_p^* is made dimensionless by the original oil in place (OOIP) instead of the OIP. Oil recovery results in Fig. 3a are striking. Recovery is greatest when solvent injection is combined with well control. After 15,000 days, net cumulative recovery approaches 80 % of the oil in place. Note that all of the solvent cases exceed 70 % recovery. With miscible (i.e., solvent) gas injection, the local displacement efficiency approaches unity and recovery is maximized.

The well-control strategy provides benefit by reducing injector to producer cycling of injected gas and thereby improves the contact of solvent with the reservoir fluid. Among the scenarios employing miscible gas injection, the well-control strategy resulted in oil recovery 7 to 12 % greater than other cases.

In the case of pure CO_2 injection, WAG with small equal-sized slugs (0.01 pore volume) of water and CO_2 recovers oil the most quickly. Ultimate recoveries of WAG and well-controlled CO_2 injection are identical, however. The main difference between these two scenarios is found during intermediate times lying between 3000 and 7000 days.

Figure 3b contrasts the injection scenarios with respect to the reservoir volume utilized. Here, pure CO_2 injection cases perform better than miscible solvent injection because only two-thirds of the solvent gas is CO_2. Of the pure CO_2 cases, continuous CO_2 injection and CO_2 injection with well control sequesters the most CO_2. Significantly, Fig. 3b demonstrates that injection of water for mobility control frustrates sequestration. The WAG cases sequester less than half of the CO_2 as does pure CO_2 injection with and without well control. Pore space is filled with water that could otherwise be filled with CO_2. Thus, WAG processes are counter to the goals of cooptimization.

The well-control strategy holds significant promise for cooptimization, as illustrated in Fig. 3c where f with equal weights is plotted versus time. Oil production from pure CO_2 injection combined with well control is on par with that obtained from an optimized WAG process while the utilization of the reservoir volume to store CO_2 is about 2.5 times that of a WAG scheme. This makes for maximum f on Fig. 3c after 15,000 days of injection. Solvent injection with well control displays maximum f between 4,000 and 12,000 days because recovery (Fig. 3a) as a result of solvent injection exceeds by a significant fraction the other techniques. In general, gas-controlled production appears to limit gas cycling while increasing both oil production and CO_2 storage by 12 to 20 %, as compared to injecting pure CO_2 or solvent gas.

The extent to which the well-control scheme reduces the volume of gas produced is illustrated in Fig. 4. The ratio of the cumulative gas upon the cumulative oil produced (cumulative GOR) is plotted versus time. Continuous CO_2 injection is contrasted with the various well control scenarios. The cumulative GOR for the well control cases varies from about 60 to 80 % of the value without well control. Substantially less gas is produced as a result of well control as indicated by the smaller area beneath the well control curves and the significantly smaller slope of the line GOR versus time.

Next, the well control method was combined with a switch in the injection gas. Results are summarized in Fig. 5. The parameters listed under WC -1 in Table 3 were used to operate the wells. In general, the fraction of oil recovered increases as the time for the switch from solvent-gas injection to pure CO_2 increases. Most of the sensitivity in recovery results is lost for a switch that occurs at roughly 4000 days or greater. On the other hand, Fig. 5b illustrates the percentage of pore volume filled with CO_2. If the switch occurs too late, maximum CO_2 is not stored. A switch from solvent gas to pure CO_2 at 4000 days or less allows us to sequester as much CO_2 as the case where pure CO_2 is injected from day zero.

Figure 5c presents f with equal weights for these cases. The volume of oil recovered is roughly equivalent to cases where solvent gas is used throughout, whereas the volume of CO_2 sequestered is equivalent to pure CO_2 injection. Accordingly, f ($w_1 = w_2 = 0.5$) is maximum when the injection gas is switched from solvent to pure CO_2 between 4000 and 8000 days. Comparing f in Figs. 3c and 5c teaches that the switch in injection gas has increased f from roughly 0.52 to 0.65 for cases where the switch occurs between 4000 and 8000 days.

4.1 Reservoir Model Invariance

The performance of the various CO_2 injection schemes is obtained above using a single reservoir model. To generalize results, it must be confirmed that the ranking of performance of the schemes is not dependent on the particular reservoir model. That is, we confirm that the well-control strategy is best invariant of the particular realization of the reservoir model.

To accomplish this goal, we employ the method and results of Part 1 [10]. In Part 1, we demonstrated that it was possible to sample in a rational fashion the spectrum of equiprobable stochastic reservoir models and select logically a subset of models that span the range of variability in reservoir performance. From 1000 reservoir models, 8 were chosen that span a range of reservoir flow performance (see Fig. 9 of [10]).

Next, 4 injection scenarios are simulated for 15,000 days using each of the 8 reservoir models. The injection scenarios include: pure CO_2 injection, WAG with 0.01 PV slugs of CO_2 and water, CO_2 injection with well control, and solvent gas injection with well control. Results are summarized in Fig. 6 for oil recovery at 15,000 days obtained from the various reservoir models with the cooptimization schemes. Figure 7 presents reservoir utilization at 15,000 days. These figures illustrate that for well control schemes and pure CO_2 injection, the sorting of results is the same for all models. That is, the oil recovery may increase or decrease from model to model, but the best performing production scenario for any given reservoir model is well-controlled injection of solvent. With respect to reservoir utilization, well control with pure CO_2 injection sequesters the most CO_2. WAG does lead to different sorting of the performances among the reservoir models; however, these deviations from the reference case do not change the conclusion that the well-controlled cases are preferred for cooptimization.

4.2 Well Control Sensitivity

The parameters used to operate the production well are producing gas-oil ratio, injection pressure, and an increase in the allowed producing gas-oil ratio each time a producer is allowed to flow. Table 3 summarizes the well-control parameter values. The initial producing gas-oil ratio and the increment to the gas oil ratio were chosen in an *ad hoc* fashion. The purpose of this section is examine the sensitivity of performance to values of the allowed gas-oil ratio and its increment. All simulations are conducted using the truth reservoir model.

Figure 8 presents the results for the sensitivity analysis of pure CO_2 injection by plotting the variation in the net cumulative recovery, Fig. 8a, and reservoir utilization functions, Fig. 8b. Figure 9 presents identical results for the injection of solvent gas. On both Figs. 8 and 9, the y-axis is the producing gas oil ratio where the production well is first shut in, whereas the x-axis is the increment made to the producing gas oil ratio each time an injection well reaches maximum pressure (350 bar) and producers must be opened to prevent overpressurization. Gray shading represents relatively low values of recovery or utilization and white represents relatively greater values.

On the one hand, Figs. 8 and 9 teach that optimal well control is obtained when the gas oil ratio where the well is first shut in is set to just slightly above the solution gas oil ratio (that is the solubility of gas in the oil). This allows one to begin controlling gas flow at just about the time that gas breaks through to the injection well. Similarly, the results show that increment to the producing gas oil ratio should be made as small as practical to obtain the best performance.

On the other hand, Figures 8 and 9 also teach that performance of the well control scheme does not depend critically on control parameters. Note the variations in maximum and minimum values on the scale of both figures. Differences in recovery and utilization among “best” and “worst” parameters settings differ by 6 to 14 %. Thus, the sensitivity analysis indicates that producing gas-oil ratio and injection pressure are robust control parameters. This well control strategy does not appear to require a high degree of parameter tuning to obtain beneficial results.

5 Conclusion

The goal to sequester maximum carbon dioxide while not diminishing rate or ultimate recovery of oil from an oil reservoir is substantially different from the goals of oil recovery alone. Carbon dioxide is relatively mobile in reservoir media because CO_2 viscosity is low as compared to oil and water. A strategy for controlling the mobility of CO_2 must be applied to prevent excessive cycling of injected gas from injector to producer. In a traditional reservoir engineering approach water and gas are injected in alternating slugs. The simultaneous flow of gas and water yields, generally, a net mobility that is less than that of injection gas alone. Water injection, however, frustrates sequestration efforts. Pore space is filled with water that could otherwise be saturated with carbon dioxide.

An effective process for cooptimization of CO_2 sequestration and oil recovery is a form of production well control that limits the fraction of gas relative to oil produced. The well control process performs optimally for all reservoir models tested. Simulation indicates that well control allows oil recovery by immiscible gas injection alone to recover virtually the same volumes as an optimized water-alternating-gas process while sequestering more than twice as much CO_2. Well control combined with solvent gas injection recovers 80 % of the oil in place while sequestering nearly the same volume as the optimized WAG recovery scheme. Of the various cases tested, the technique leading to maximum oil recovery and CO_2 left in the formation at the end of the recovery process is a well control process with a switch in the composition of the injection gas. Solvent is injected initially to obtain maximum oil recovery and then the injectant is switched to pure CO_2 after roughly half of the oil in place has been recovered. The switch in injection gas composition allows maximum sequestration.

Nomenclature and Abbreviations

BHP	bottom-hole pressure, bar or MPa
D	design equation
E	compression energy, barrel of oil equivalent
f	objective function, dimensionless
GAW	gas after water
GOR	gas-oil ratio, dimensionless

k_r	relative permeability, dimensionless
N_p	cumulative oil recovery, barrel or m^3
N_p^*	N_p discounted for energy to compress recycled gas,barrel or m^3
OIP	oil in place
OOIP	original oil in place
P	compressor operating pressure, lb_f/ft^2
PV	pore volume, dimensionless
Q	flow rate, ft^3/min
S	saturation, dimensionless
t	time, days
w	weights in objective function, dimensionless
V	volume, m^3
WAG	water alternating gas
WC	well control

Greek

γ	compressibillity factor, dimensionless

Superscripts and Subscripts

1	denotes weight for oil recovery
2	denotes weight for CO_2 storage
$COOP$	denotes a cooptimized function

CO_2	denotes volume of CO_2 in reservoir
g	gas phase
i	injected
in	denotes inlet pressure of gas compressor
o	oil phase
og	two-phase system composed of oil and gas phases
out	denotes exit pressure of gas compressor
R	reservoir
$trad$	denotes a traditional oil recovery function
w	water phase

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Table 1

Compositional description of crude oil.

Component	Mole fraction	Molecular weight kg/mol	T_c (K)	P_c (bar)	Accentric factor
carbon dioxide, CO_2	0	0.04401	304.2	72.9	0.228
methane, CH_4	0.4383	0.01604	190.6	45.4	0.008
ethane, C_2H_6	0.04262	0.03007	305.4	48.2	0.098
propane, C_3H_8	0.009153	0.04410	369.8	41.9	0.152
i-butane, C_4H_10	0.005824	0.05812	408.1	36.0	0.176
n-butane, C_4H_10	0.005395	0.05812	425.2	37.5	0.193
i-pentane, C_5H_12	0.006771	0.07215	460.4	33.4	0.227
n-pentane, C_5H_12	0.003081	0.07215	469.6	33.3	0.251
hexanes, C_6	0.01063	0.08617	507.4	29.3	0.296
heptanes, C_7	0.2359	0.1355	623.9	30.4	0.449
$C_8 - C_{15}$	0.1189	0.2489	708.6	20.4	0.804
$C_{16} - C_{23}$	0.07894	0.3812	795.7	16.5	1.119
$C_{24}+$	0.04456	0.6322	947.9	14.5	1.317

Table 2

Composition (mole fraction) of injection gases.

Component	Lean Gas	Solvent Gas
carbon dioxide, CO_2	1.000	0.667
ethane, C_2H_6	0.000	0.125
propane, C_3H_8	0.000	0.125
n-butane, C_4H_{10}	0.000	0.083

Table 3

Summary of well-control scheme

	Producer GOR (m^3/m^3)	Injector BHP (bars)	Average Reservoir Pressure (bars)	Increment to GOR (m^3/m^3)
WC –1	500	350	n/a	250
WC–2	500	300	n/a	100
WC–3	500	n/a	300	100

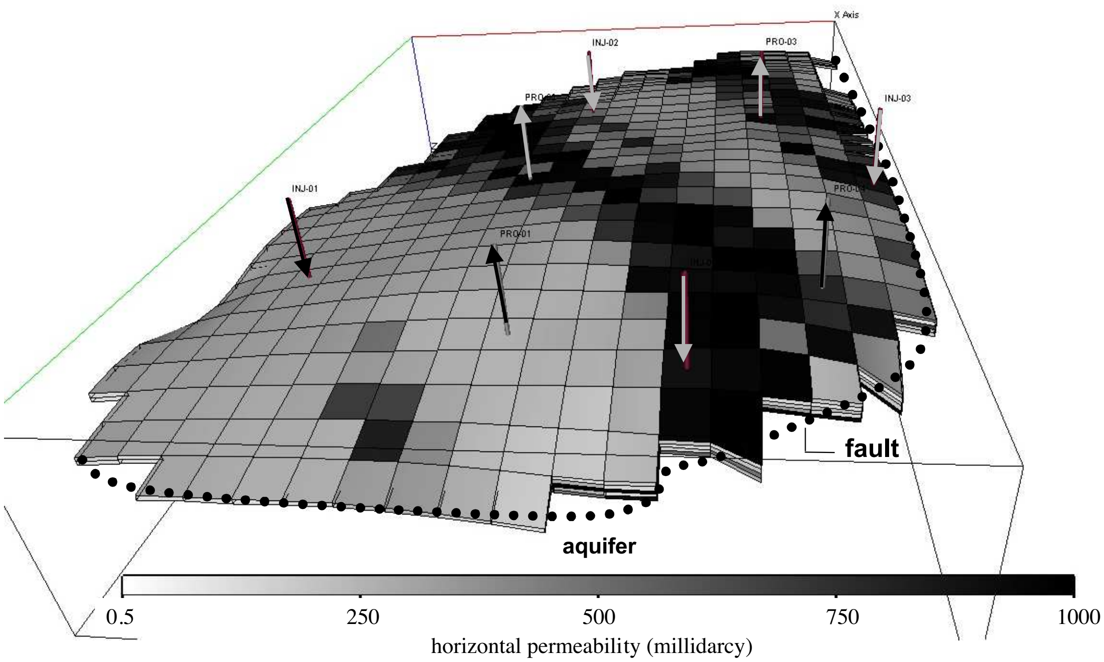


Fig. 1. Reservoir architecture: distribution of horizontal permeability (md). Arrows indicate location of injection (downward) and production (upward) wells.

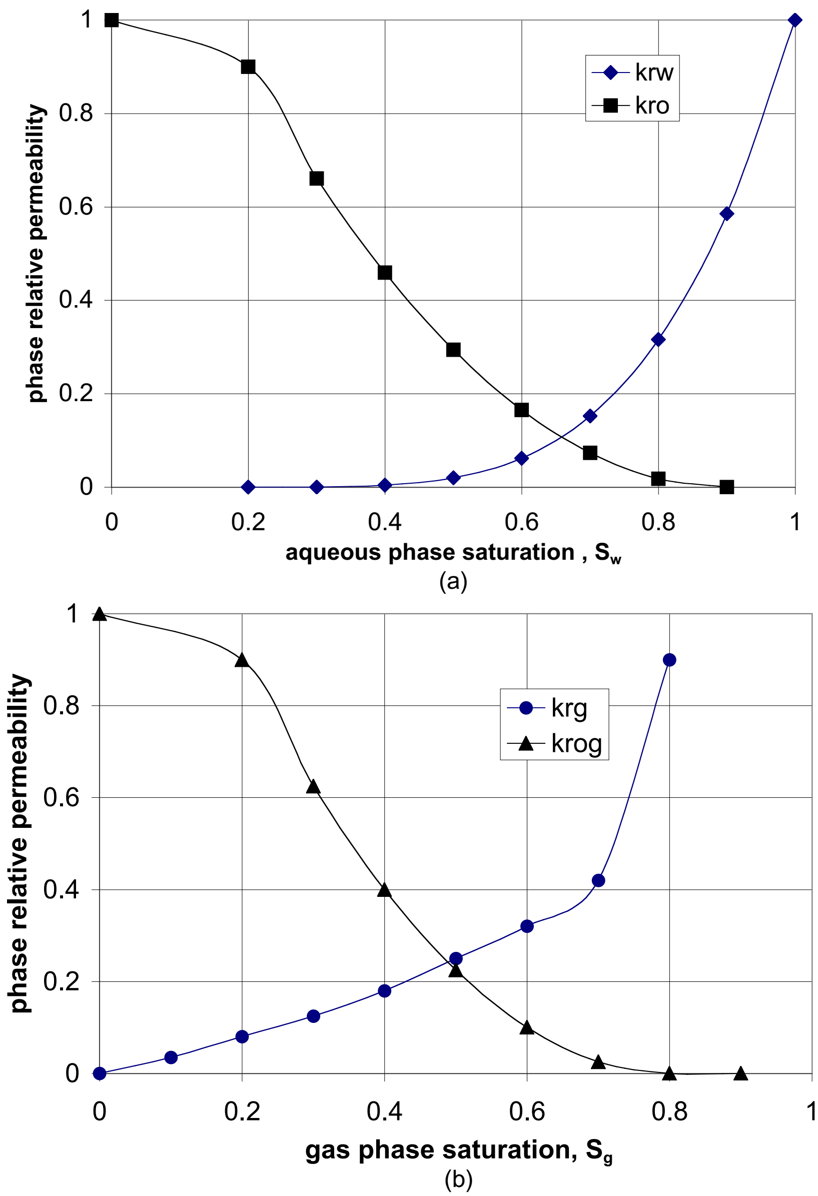


Fig. 2. Two-phase relative permeability relationships: (a) water and oil and (b) oil and gas.

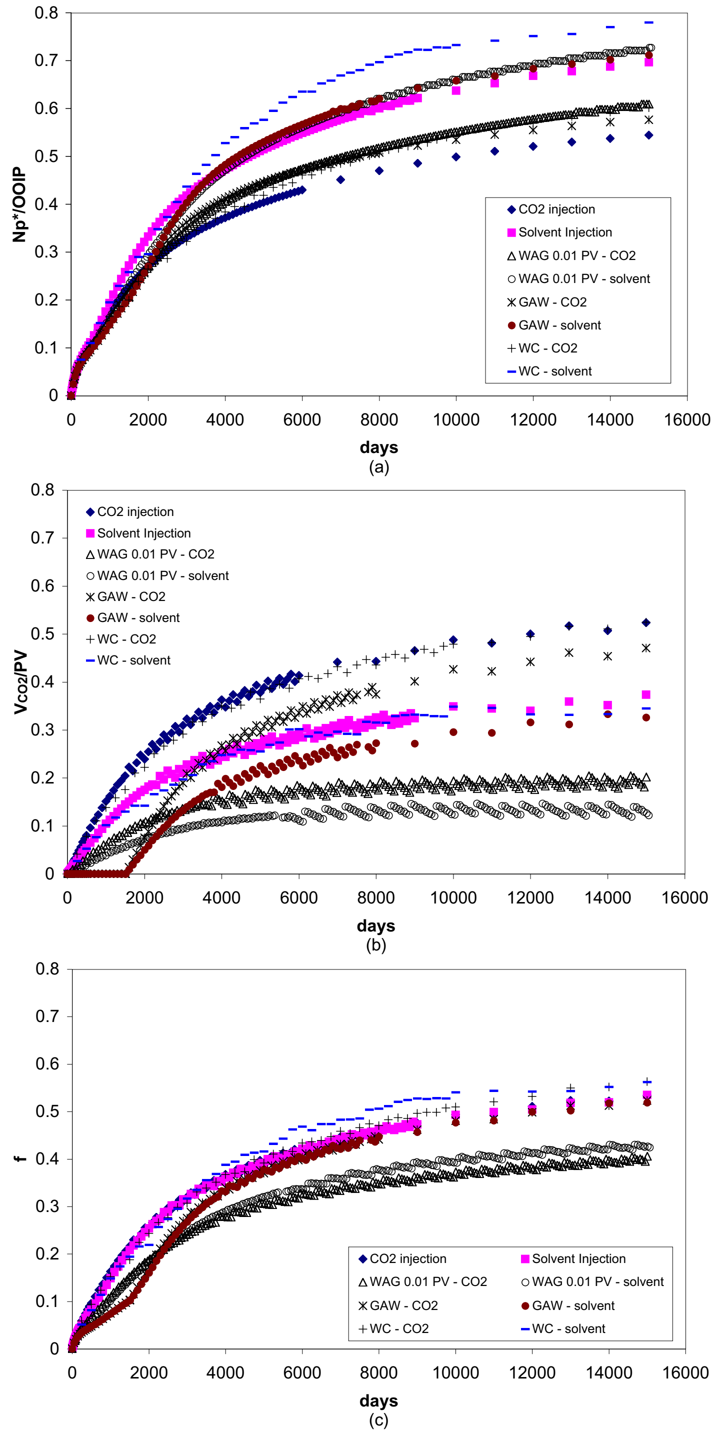


Fig. 3. (a) Oil recovery, (b) reservoir utilization performance, and (c) cooptimization ($w_1 = w_2 = 0.5$) of different gas injection processes from a 3D, compositional reservoir example.

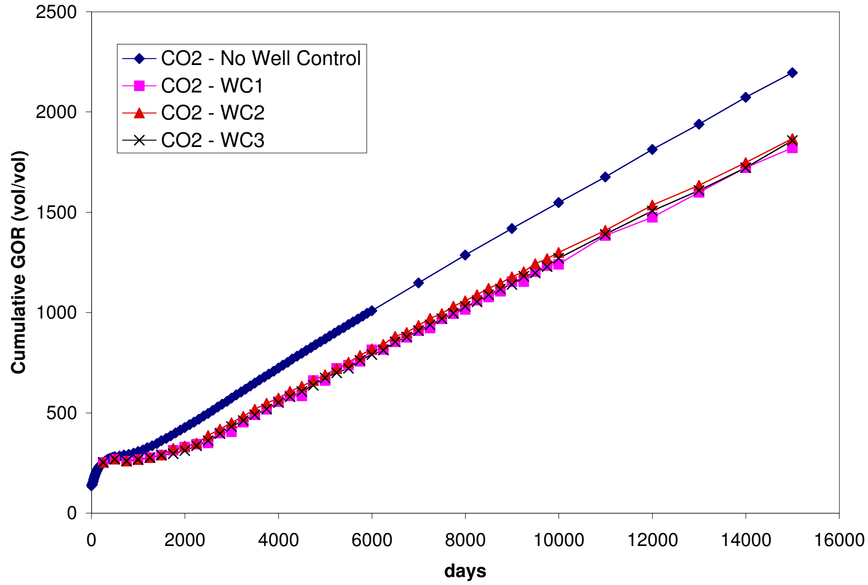


Fig. 4. Cumulative gas-oil ratio versus time for continuous CO_2 injection as compared to well-control schemes.

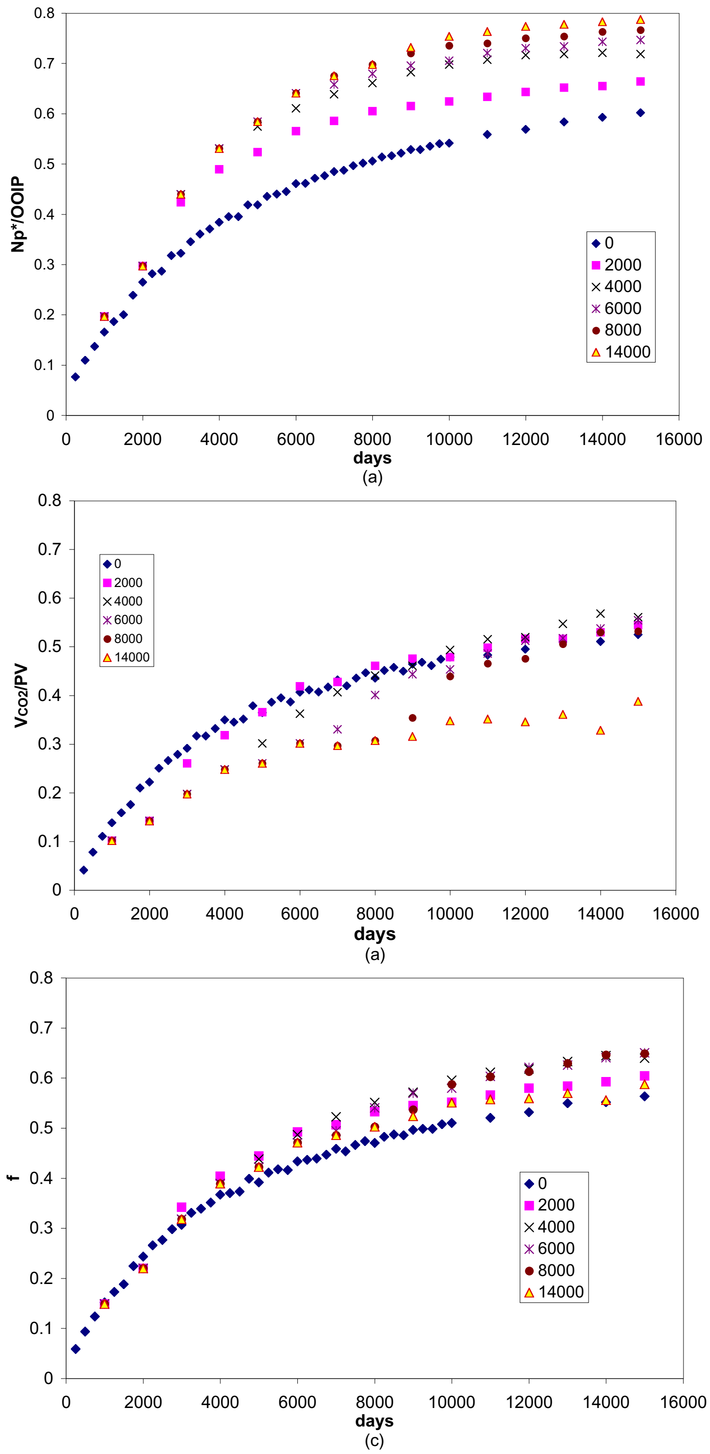


Fig. 5. Performance of well-control scheme when the injectant is switched from solvent gas to pure CO_2. Legend lists the time in days when the switch occurs: (a) Oil recovery, (b) reservoir utilization performance, and (c) cooptimization ($w_1 = w_2 = 0.5$).

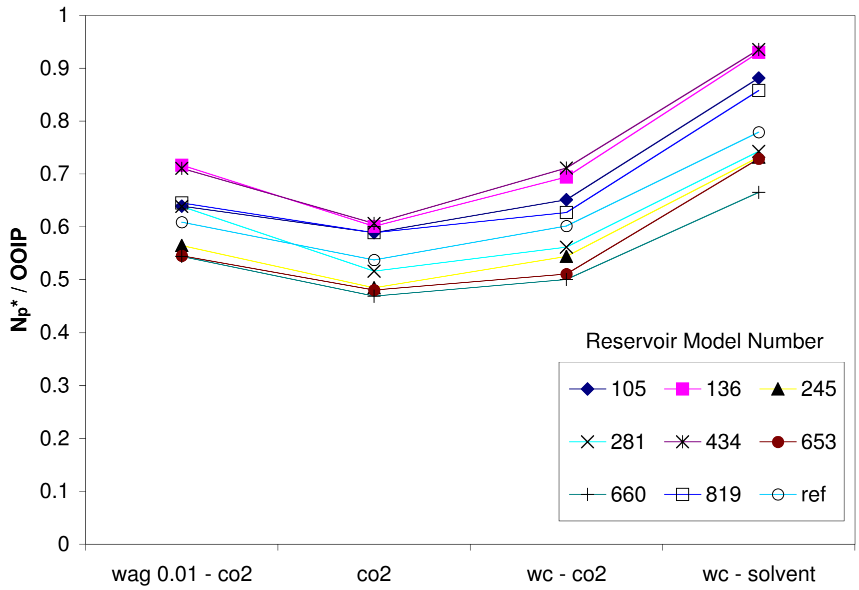


Fig. 6. Oil recovery comparison of 8 equiprobable reservoir models selected by a streamline-based proxy.

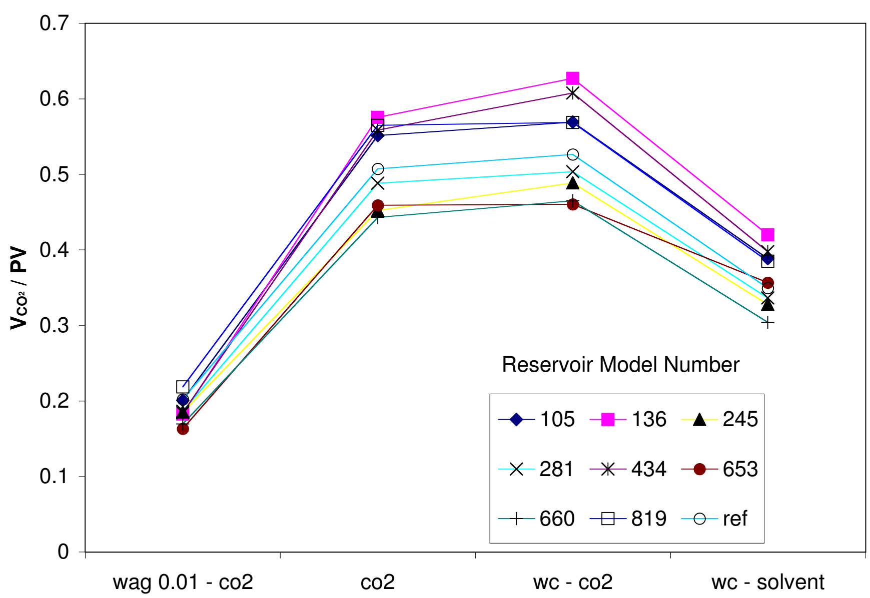
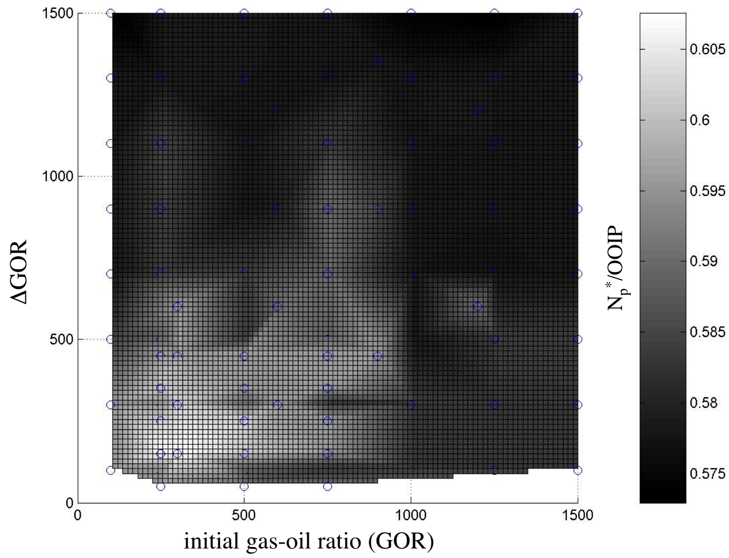
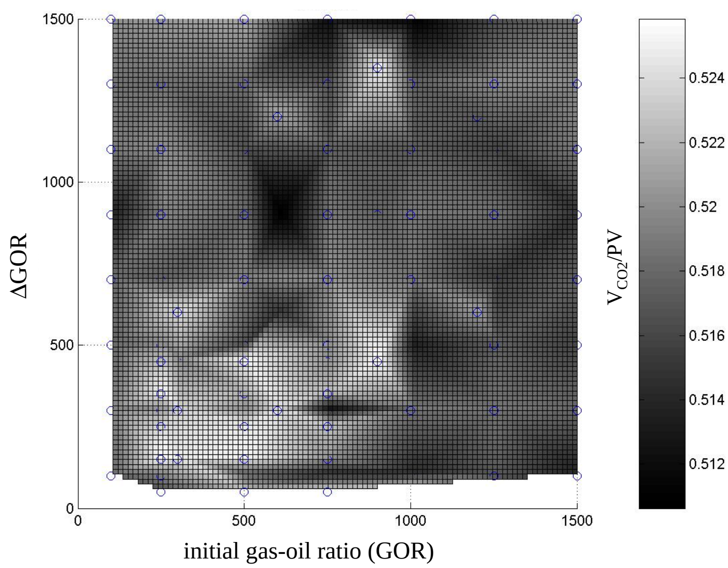


Fig. 7. Reservoir utilization comparison of 8 equiprobable reservoir models selected by a streamline-based proxy.

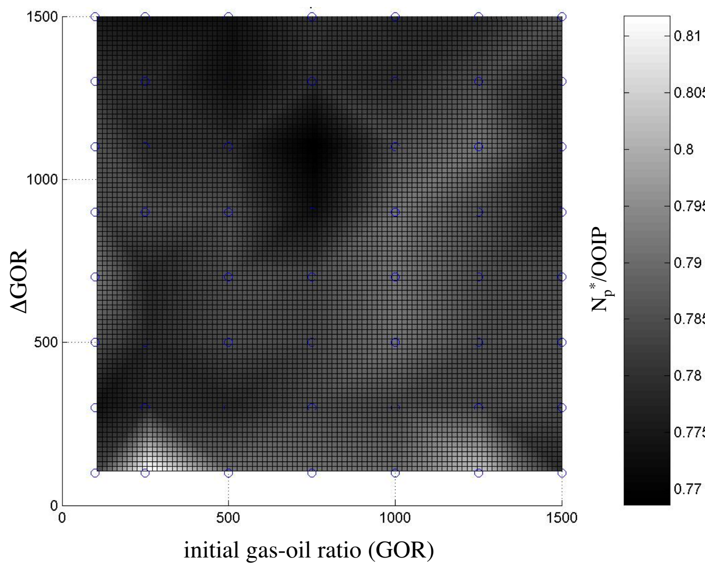


(a)

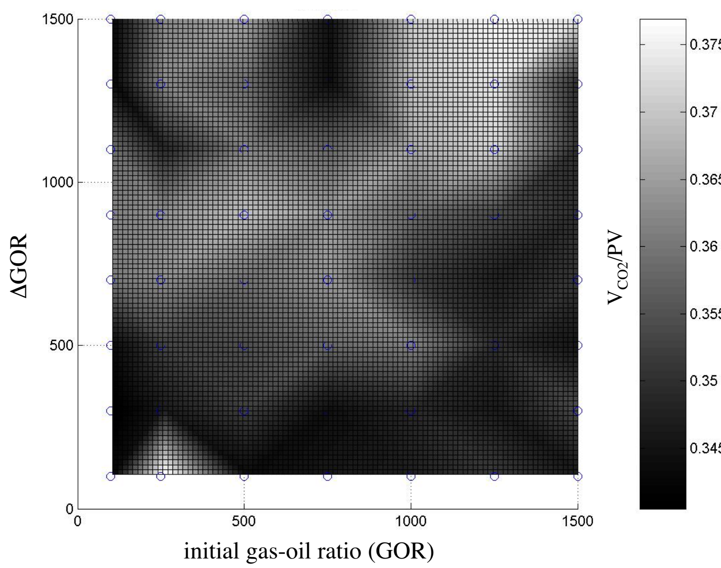


(b)

Fig. 8. Sensitivity of (a) net cumulative recovery and (b) reservoir utilization results to well-control parameters. Pure CO_2 is injected.



(a)



(b)

Fig. 9. Sensitivity of (a) net cumulative recovery and (b) reservoir utilization results to well-control parameters. Solvent gas is injected.